Shale Gas Potential as a Transportation Fuel and for Added Electricity Supply with Implications for Solar and Wind Energy

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Abstract

The U.S. has abundant natural gas resources. This has led to proposals to expand the use of natural gas as a transportation fuel to reduce oil consumption and for added electricity supply to reduce CO_2 emissions. The findings of this research indicate that natural gas supplies are sufficient to sustain current consumption levels post-2050. If natural gas supplies are used to support the expanded use of natural gas as a transportation fuel or for added electricity supply, then natural gas prices will likely increase to greater than $10/Mcf by 2040. Also, shale gas supply may be constrained in response to the growing concerns about hydraulic fracturing causing pollution of potable water supplies and waste-water disposal issues. These findings call into question the prudence of proposals to export U.S. natural gas to foreign countries. Long-term stability of natural gas prices is important because of the widespread use of natural gas for space and water heating.

The conclusion of this study suggests adoption of policies that enhance rather than diminish long-term natural gas supply. One such policy is the large-scale expansion of solar and wind electricity production with the variable solar and wind electricity supply firmed with compressed air energy (CAES) power plants, which have a very low natural gas consumption rate. The solar and wind electricity path has the potential to reduce natural gas use by over 3 Tcf/year. Also, the solar and wind electricity path enables the large-scale adoption of electric vehicles, which would reduce oil consumption and enable the U.S. to reduce CO_2 emissions by more than 50%.

The following is a summary of long-term shale gas production and price findings:

1. Shale gas E&P (exploration and production) companies concentrate well development in the highest quality, core areas of shale gas plays. When core areas are saturated with well development, average well production rates decline, and wellhead gas prices increase. Based on current drilling practices, it is assumed that core areas of shale gas plays will be developed with 80 acre well spacing and 4-5,000 foot laterals.
2. There is large variation in well production rates across the areas of a shale gas play because of spatial variation in geological properties. The areas of shale gas plays are categorized in terms of the highest quality core area and the lower quality extension areas, with quality being defined in terms of average well production rates. The average well production rate of extension areas is about 50% less than the average well production rate of core areas.
3. When the core areas of all shale gas plays are saturated with well development, shale gas wellhead prices will increase to more than $10/Mcf.
4. Based on EIA projected shale gas production levels through 2035, the core areas of all major U.S. shale gas plays will be saturated with well development by 2040. This finding includes an annual supply of Alaska North Slope natural gas at a rate of 4.5 Tcf by 2035.
5. Conclusion, when the Marcellus core area is saturated with well development, all other core areas of shale gas plays will be saturated with well development. This result is based on the fact that the Marcellus core area is by far the largest core area of all U.S. shale gas plays.

1. Introduction

Over the last decade U.S. natural gas forecasts have gone from famine to feast. In 2001 U.S. natural gas production began to decline when offshore gas production unexpectedly went into decline. This created a supply shortage and steep price increases.

The natural gas price increases created an incentive to pursue large-scale development of the nation's shale gas resources. The success of shale gas production created a rebound in U.S. natural gas production. By 2008, natural gas production exceeded the 2001 level. The rapid growth in shale gas production coupled with the 2008-2009 recession led to a natural gas supply surplus and a collapse in natural gas prices. Today, shale gas is the single largest source of natural gas supply and contributed about 20% of total U.S. natural gas supply in 2010.

The importance of shale gas is evident in the Energy Information Administration's (EIA) *Annual Energy Outlook 2011* forecast of U.S. natural gas supply through 2035 [1]. The EIA natural gas supply forecast to 2035 is presented in Fig. 1. Shale gas supply is projected to increase from 5 trillion cubic feet (Tcf) in 2010 to 12 Tcf in 2035 and is the marginal unit of natural gas supply.

The EIA natural gas forecast is for business-as-usual natural gas use patterns. It does not include the expanded use of natural gas as a transportation fuel or for added electricity generation. Nor does it include a large increase in solar and wind electricity supply. This study evaluates the effect of expanded natural gas use scenarios on long-term natural gas supply and price dynamics.

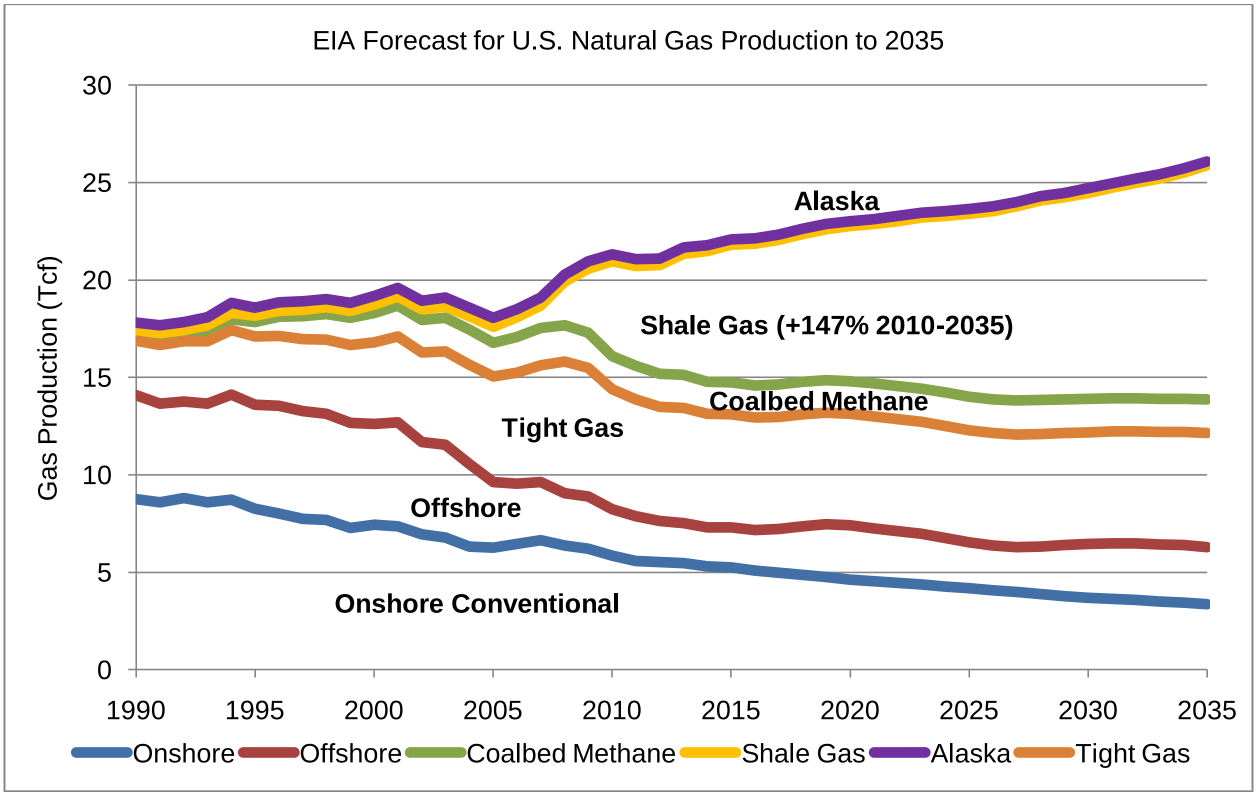


Figure 1. U.S. natural gas supply by source gas, 1990-2035. Source: EIA, 2011.

EIA natural gas resource estimates are presented in Table 1 [1]. The natural gas resource estimates are technically recoverable resources (TRR). TRR is an estimate of the size of the resource base that can be produced with current technology, but it does not include economic factors. Historical U.S. natural gas supply has progressed from the most available and least costly resources to the ever less available and more costly resources. Natural gas production from conventional onshore and offshore resources is declining. Future U.S. natural gas supply will be increasingly reliant on shale gas and Alaska North Slope natural gas resources.

Table 1. U.S. Natural Gas Resource and Production Estimates (Trillion Cubic Feet, Tcf).[a]

	TRR (2010)[b]	Past Production (1900-2009)	URR (Past Production + TRR)[b]	Cumulative Production (1900-2035)	Cumulative Production % of URR
Conventional Onshore (lower 48)	579	730	1,309	846	65%
Offshore (lower 48)	296	160	456	226	49%
Coalbed Methane (lower 48)	125	26	151	70	46%
Tight Gas (lower 48)	310	115	425	266	63%
Shale Gas (lower 48)	847	15	862	240	28%
Alaska	302	8	310	16	5%
Totals	2,459	1,056	3,515	1,664	47%

Notes:

a. The data source is Energy Information Agency (EIA).

b. The ultimate recoverable resource (URR) is the sum of technically recoverable resources (TRR) and past production.

With the recent addition of substantial shale gas resources to the U.S. natural gas resource base, the natural gas industry claims that there is over a hundred years of natural gas supply at current consumption rates. This is motivating proposals to expand the use of natural gas as a transportation fuel and for added electricity supply. Since shale gas is the marginal unit of natural gas supply, this study investigates the impact of expanding natural gas use on long-term shale gas production and price dynamics.

2. Shale Gas Production

Only in last decade has shale gas production become a significant source of natural gas supply. It has long been known that some shale rock formations are rich in natural gas content, but extracting it in commercial quantities was a problem. Vertical shale gas wells have been drilled since the 1880's, but total natural gas production was less than a billion cubic feet (Bcf) per well.

The shale gas revolution began when Mitchell Energy (now Devon) demonstrated in the Texas Barnett play that shale gas can be produced on a commercial scale with a combination of horizontal drilling, hydraulic fracturing, and 3-D seismic imaging. While horizontal wells are more expensive than conventional vertical wells, the gas production rate of horizontal wells is a factor of three greater than vertical wells [2]. Schematics of vertical and horizontal shale gas wells are presented in Fig. 2 and Fig. 3. The vertical orientation of horizontal well fracturing enables the exploitation of natural fractures in shale formations and increases gas flow rates.

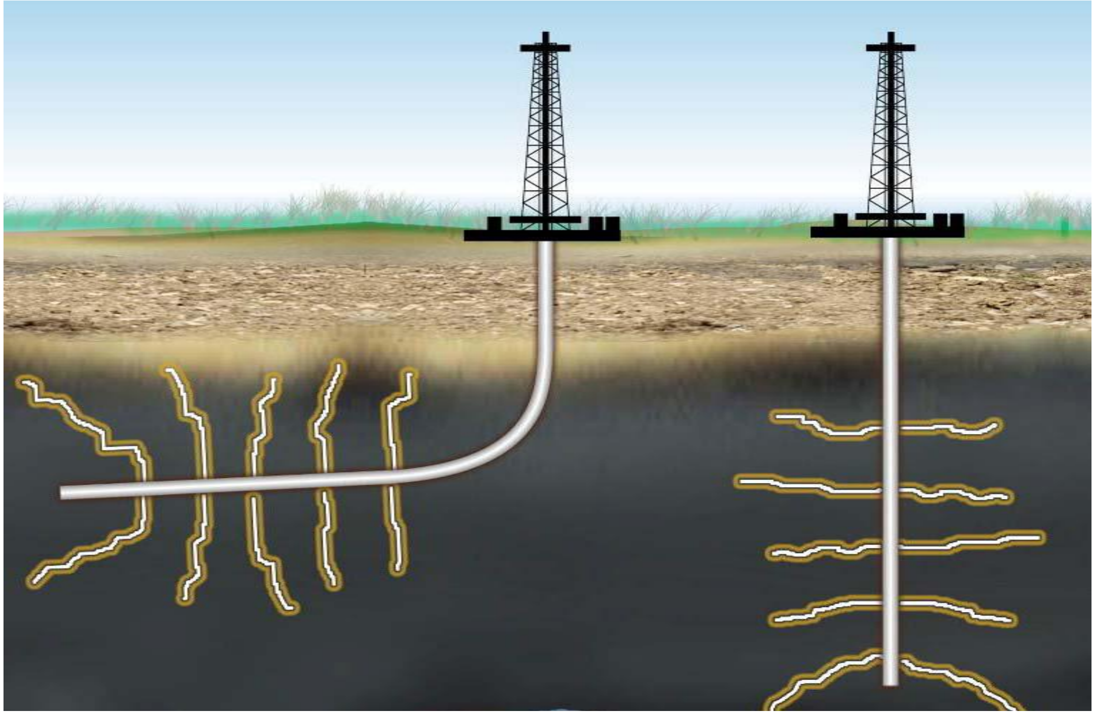
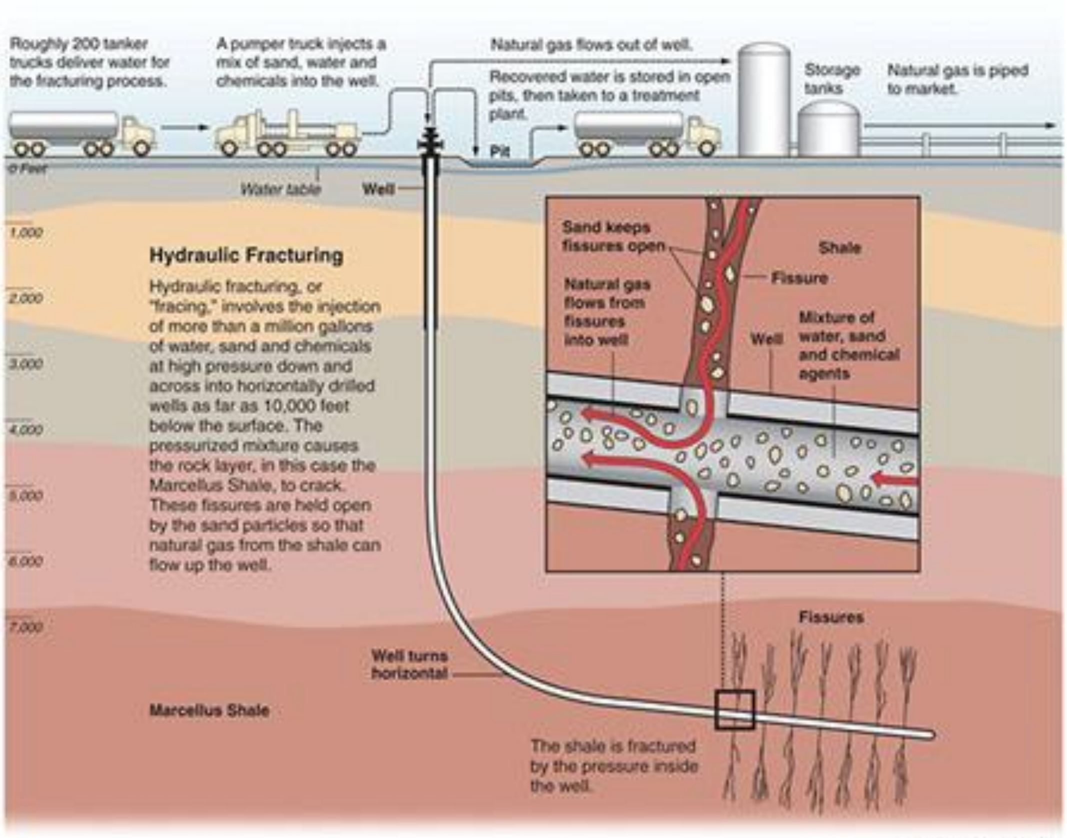


Figure 2. Schematic of horizontal (left) and vertical (right) wells with hydraulic fracturing.



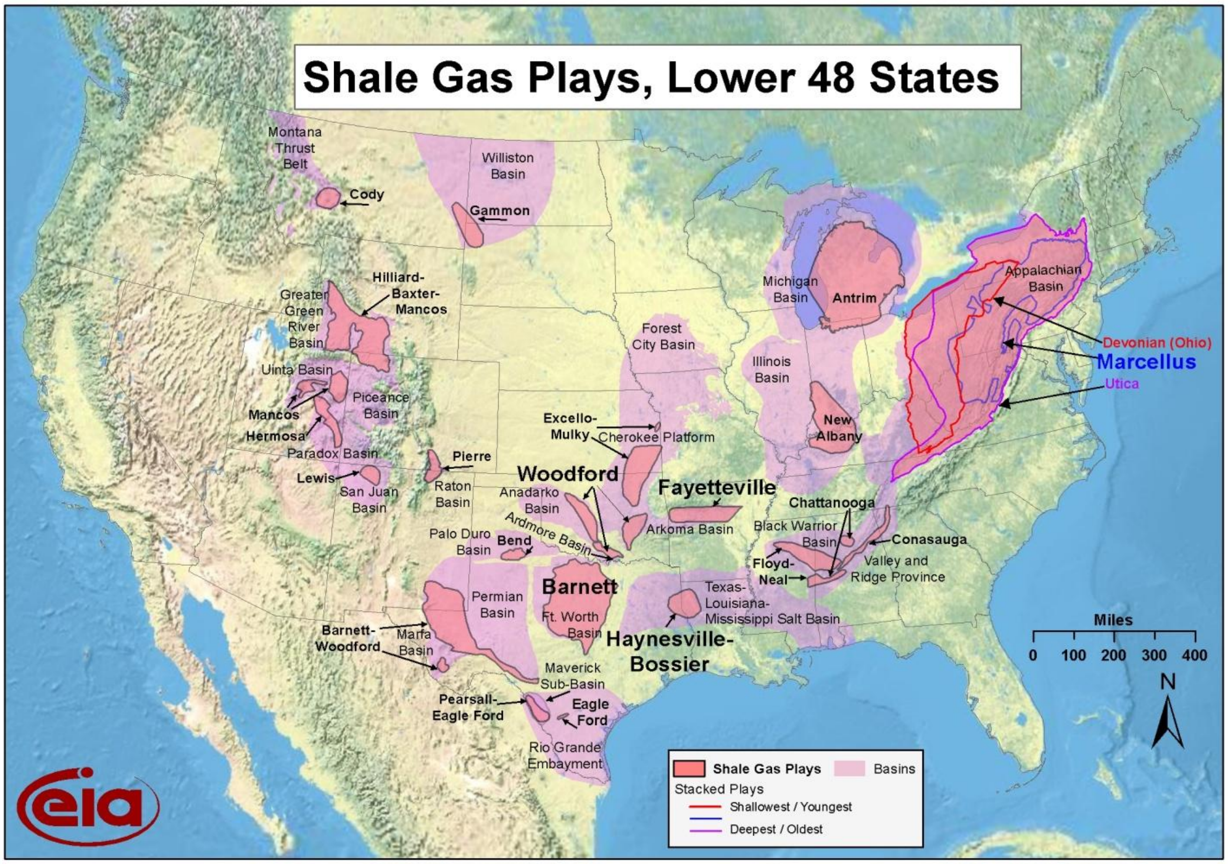
Graphic by Al Granberg

Figure 3. Hydraulic fracturing for horizontal shale gas wells.

The success of horizontal shale gas production in the Barnett play instigated a mad dash by exploration and production (E&P) companies to secure leases in shale gas plays. U.S. shale gas plays are shown in Fig. 4. To secure long-term lease rights to acreage positions in the shale gas plays, E&P companies have to bring wells into production on term-leased acreage within a contractual length of time, generally three years, or lose their lease rights.[1] From 2002 to 2010, shale gas production grew from virtually zero to 5 Tcf. The result has been a surplus in natural gas supply and a sharp decline in natural gas prices from the high 2008 prices.

2-A. Shale Gas Play Characteristics

Horizontal hydraulic fracturing of shale gas wells has a short history but much has been learned. Data availability for horizontal well production is: nine years for the Barnett play; five years for the Fayetteville play; three years for the Haynesville play; and two years for the Marcellus play.



Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

Figure 4. EIA map of shale gas plays in the lower 48 States.

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[1] As an example, the following is an extract from a Petrohawk Energy press release about their 2011 drilling plans for the Haynesville play. "Petrohawk Energy has been engaged in a drilling frenzy in the Haynesville Shale the last few years in order to convert its term acreage to held by production, and the company estimates that 280 operated sections and 590 non-operated sections will held by production by the end of 2011. Petrohawk Energy reported that it will have to drill another 145 wells in 2012 (25 operated and 120 non-operated) to complete the lease capturing process in the Haynesville Shale" [3].

The shale gas production analyses in this study are based on data from published studies, E&P company presentations, and original analyses of the Fayetteville and Marcellus plays with State of Arkansas and State of Pennsylvania shale gas production data.

While shale rock formations are continuous and extend over large areas, there is large variation in well production rates because of area specific geologic factors. Some of the most important geologic factors affecting shale gas production rates are: gas-in-place (GIP; shale thickness; thermal maturity; shale depth; and the distribution of natural fractures [2, 4]. Shale thickness is important because it correlates with GIP, thermal maturity, and well production rates.

Thermal maturity is important because natural gas is formed by the decay of organic matter trapped in the shale rock formation. Thermal maturity is a measure of the degree to which trapped organic matter has decayed into a gaseous natural gas state as opposed to decaying into liquid hydrocarbon states such as oil, natural gas liquids, and lease condensates. The higher the thermal maturity rating of an area, the greater is the volume of dry natural gas.

Shale depth is important because hydrostatic pressure and temperature increase with depth. Higher pressures and temperatures enhance natural gas formation processes. Also, bottom-hole pressure correlates with well production rates. Hence, over-pressurized areas of shale gas plays are preferred. The distribution and orientation of natural fractures in shale formations influence the effectiveness of hydraulic fracturing in opening pathways for gas recovery.

In the initial development phase of a shale gas play, E&P companies identify the areas that are characterized by thicker, deeper, and higher thermal maturity shale formations. Shale gas plays are classified in terms of core and extension areas. Core areas are the thicker, deeper, and higher thermal maturity portions of the shale play. Extension areas are the thinner, shallower, and lower thermal maturity portions of the shale play. Well natural gas production rates are significantly greater in the core areas compared with those in the extension areas.

For example, the core area of the Barnett play is up to 900 feet thick and has an average GIP of 150 Bcf/mi^2 [4]. In contrast, the lower quality extension areas are about 200 feet thick and have an average GIP of 50 Bcf/mi^2. The average expected ultimate recovery (EUR) rate of core area wells is over 2 Bcf/well, while the average EUR rate of Tier 1 extension area wells is less than 1.5 Bcf/well. Hence, core area production is important to maintain low prices.

The core and extension areas of the Barnett, Haynesville, and Marcellus shale gas plays are presented in Fig. 5. Notice that the core area of a play comprises only 10-15% of the total area. Shale gas E&P companies concentrate production in the highest quality core areas. The distribution of natural gas production wells in the Fayetteville, Barnett, Haynesville, and Marcellus plays are presented in Fig. 6. Notice the correlation of the well clusters in Fig. 6 with the core areas shown in Fig. 5.

There are two well clusters in the distribution of wells in the Marcellus play. One well cluster is in northeast Pennsylvania, and the other well cluster is in southwest Pennsylvania. The northeast Pennsylvania well cluster represents wells producing dry natural gas. The well cluster in southwest Pennsylvania represents wells producing wet natural gas.

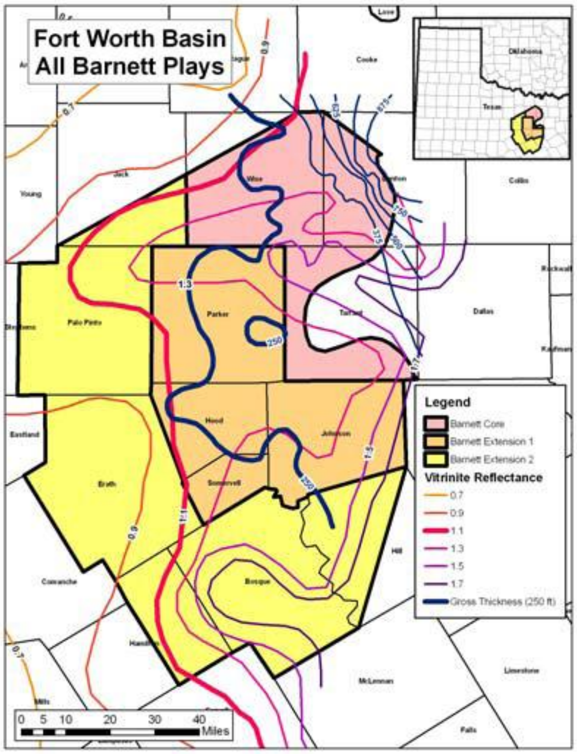

Fig. 5-a. Barnett play core area in pink.

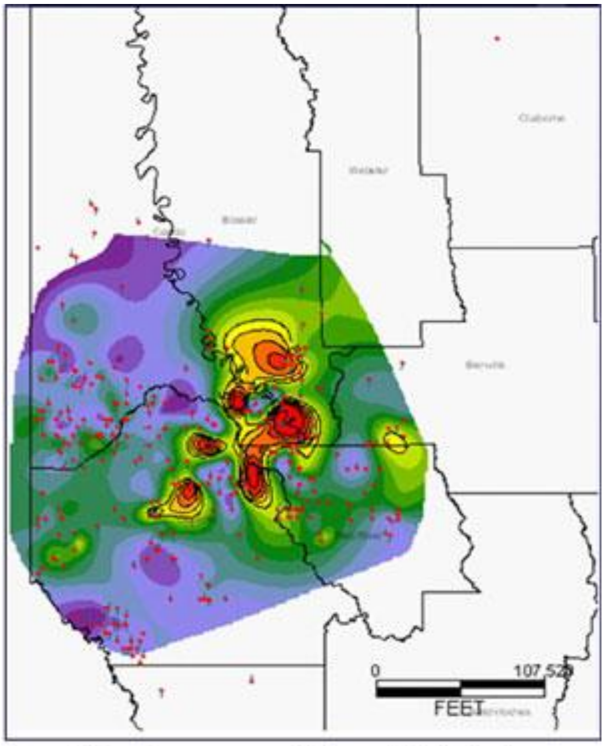

Figure 6. Emerging core area of Haynesville Shale play.

Fig. 5-b. Haynesville core in red and yellow.

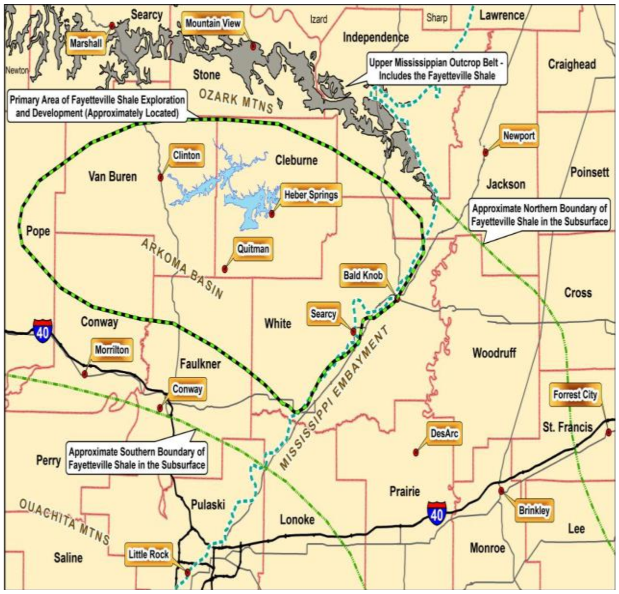

Fig. 5-c. Fayetteville core area is circled.

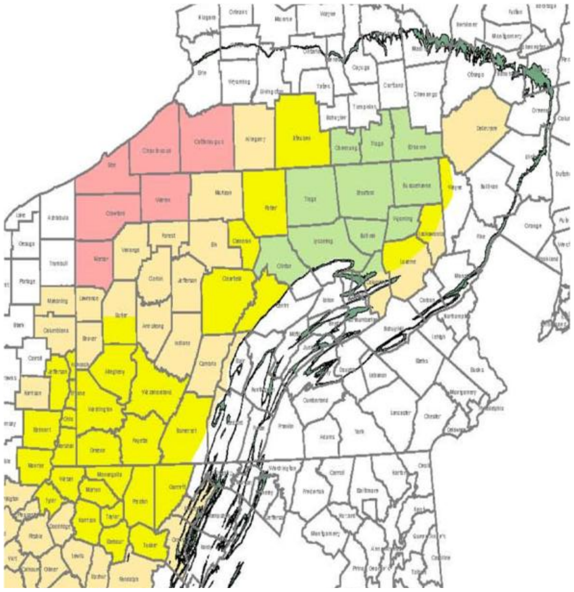

Fig. 5-d. Marcellus core in green (NY-PA).

Figure 5. Core and extension areas of the Barnett, Haynesville, and Marcellus shale gas plays.

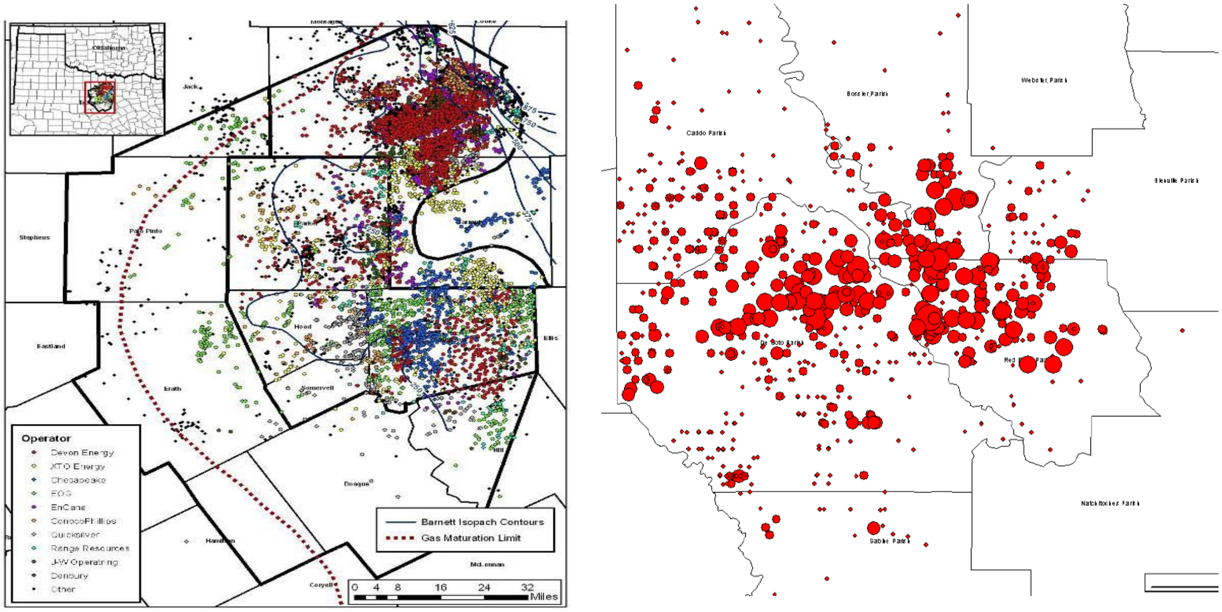

Fig. 6-a. Barnett Play well locations.

Fig. 6-b. Haynesville Play well locations.

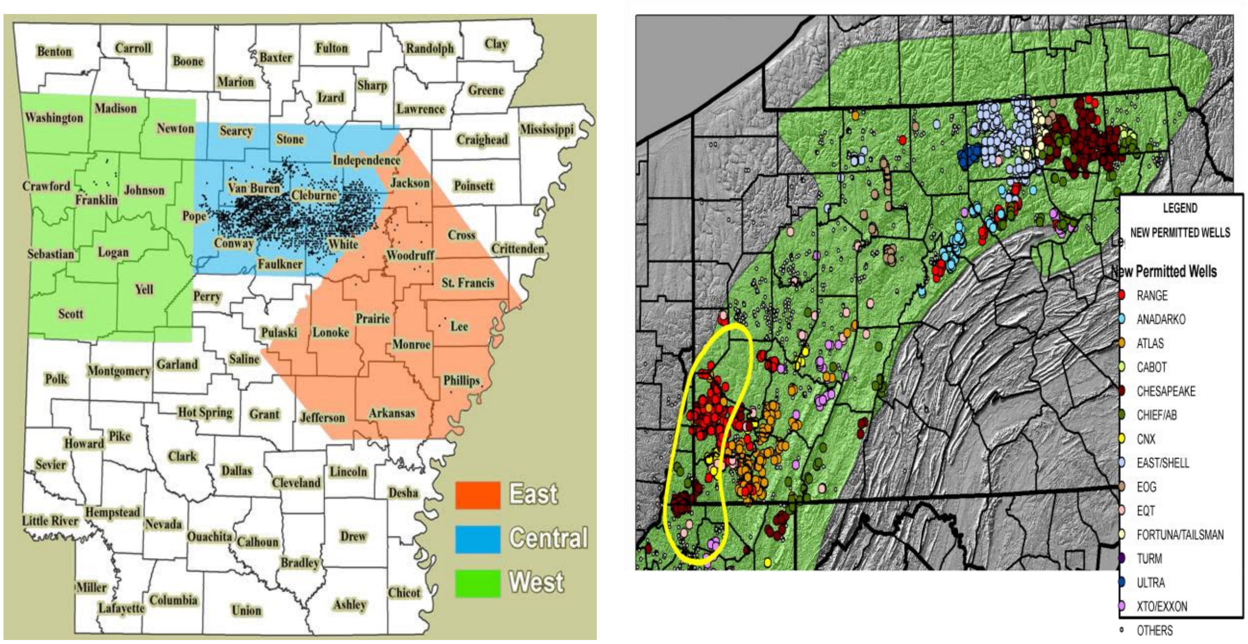

Fig. 6-c. Fayetteville Play well locations.

Fig. 6-d. Marcellus Play well locations.

Figure 6. Distribution of wells in a. Barnett, b. Haynesville, c. Fayetteville, and d. Marcellus.

Wet natural gas wells produce hydrocarbon liquids such as crude oil, crude oil condensates, and natural gas liquids (ethane, propane, and butane) in addition to dry natural gas. The hydrocarbon liquids are separated at processing plants and when sold provide additional revenue streams to well operators. Hence, extension area wells with relatively low natural gas production rates can be profitable with the revenues from the sale of hydrocarbon liquids.

However, the natural gas production rates of wet wells are significantly less than those of dry wells located in the core areas of shale gas plays. Therefore, for this analysis of shale gas production rates the core area of the Marcellus play is in northeast Pennsylvania. Also, it should be noted that a portion of the Marcellus core area is in New York State.

Area variation in average well production rates for the Barnett, Fayetteville, and Marcellus plays are shown in Figs. 7a–7c respectively. The Marcellus Washington county data are wet wells. The average well production data sources are: a Powell Barnett Shale Newsletter study of the Barnett play; original analysis of Arkansas Oil & Gas Commission data for the Fayetteville play; and original analysis of Pennsylvania Department of Environmental Protection (PADEP) data for the Marcellus play [5, 6, 7]. For the Fayetteville play, only county well production rates are reported because the play has not yet been classified in terms of core and extension areas.

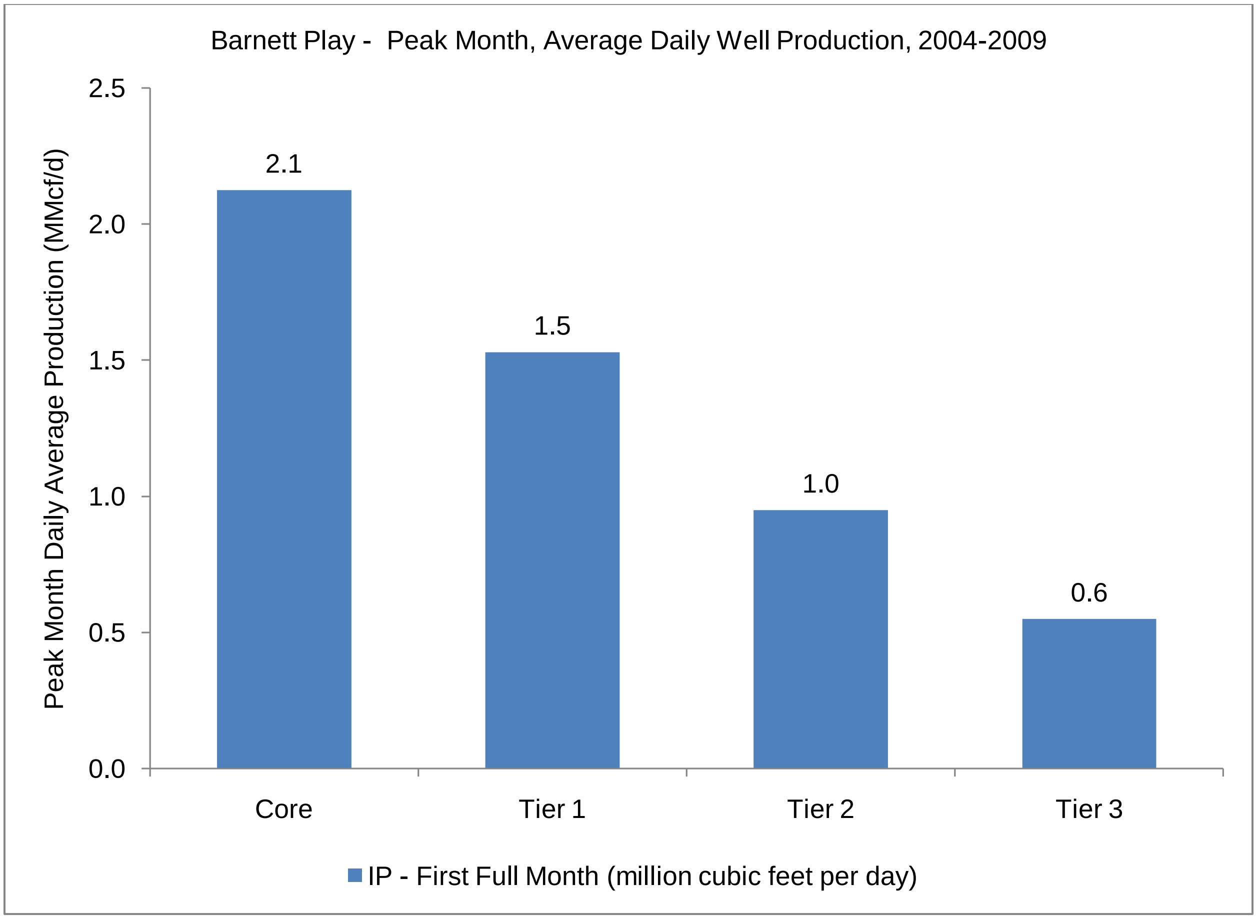

Figure 7a. Barnett Play – average daily well production in first full month of production. The well production rates are for dry natural gas and do not include hydrocarbon liquids production.

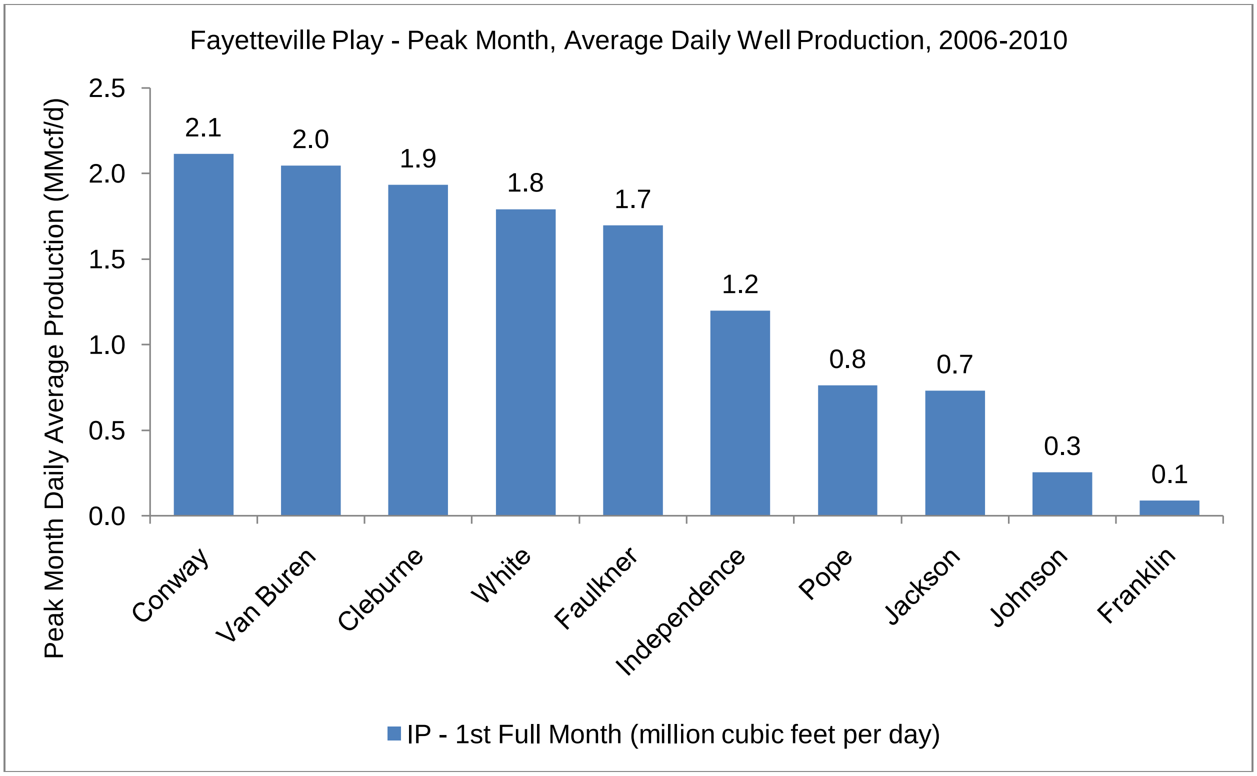

Figure 7b. Fayetteville Play - average daily well production in first full month of production.

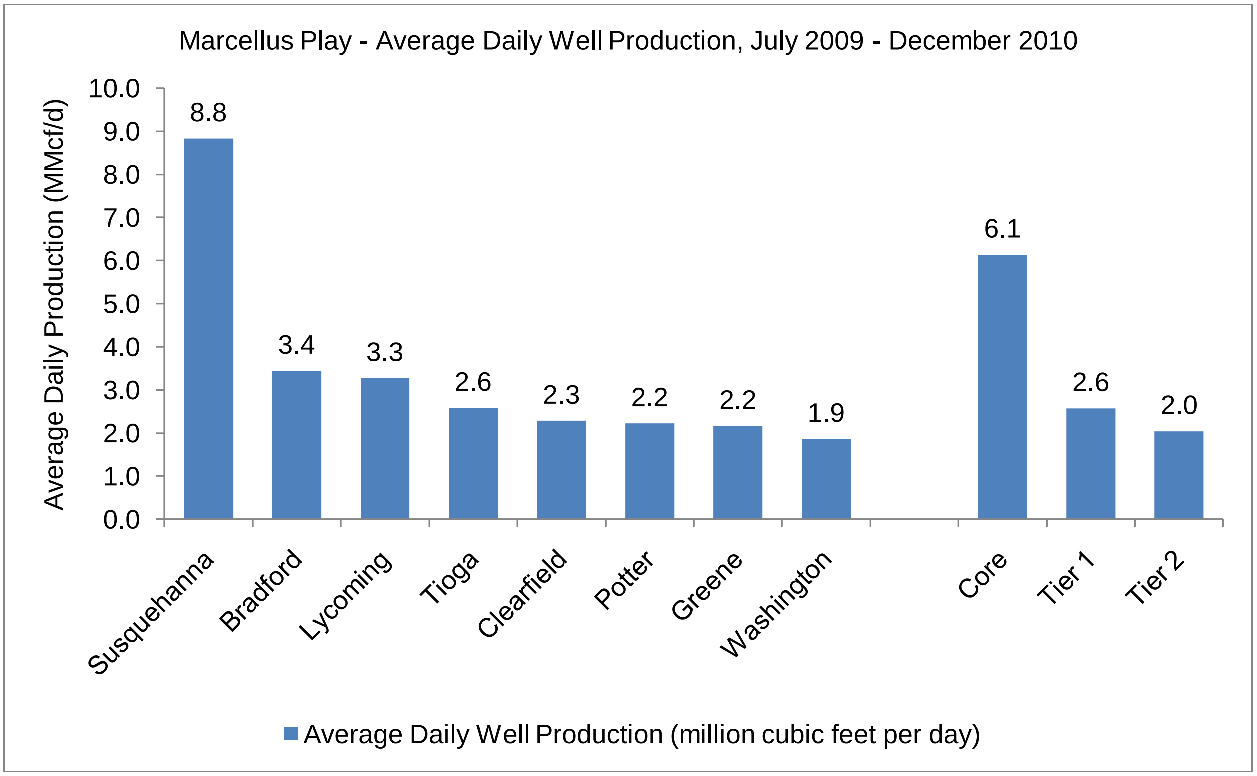

Figure 7c. Marcellus Play, average daily dry gas production for wells completed post-June 2009.
Figure 7. Well production rates for dry natural gas, excluding hydrocarbon liquids production.

2-B. Average Horizontal Well Production Profiles and Wellhead Gas Prices

Wellhead natural gas prices are of central importance. The estimation of wellhead gas prices is based on average well costs and average well production rates. The observed variation in well production rates across areas of a shale gas play is important because as a play develops over time from production concentrated in the core area to production concentrated in the extension areas, there will be a decrease in the play's average well production rate, which in turn will increase the long-term trajectory of wellhead gas prices.

Average horizontal well production rates and costs are presented in Table 2.

Table 2. Shale Gas Horizontal Well Production and Cost Estimates.[a]

	Barnett	Fayetteville	Marcellus	Haynesville
Expected Ultimate Recovery (EUR)	3.0 Bcf	2.6 Bcf	5.25 Bcf	6.5 Bcf
Initial Production (IP First Month)	2.7 MMcf/d	2.1 MMcf/d	4.0 MMcf/d	10.6 MMcf/d
Risk Factor	15%	20%	60%	30%
Estimated Drilling Density (Acres)	60	80	80	80
Finding and Development Costs	\$1.24/Mcf	\$1.48/Mcf	\$1.14/Mcf	\$1.60/Mcf
Drilling Costs (\$ millions)	2.8	3.2	5	7.8
B-Factor (Hyperbolic Formula)	1.6	1.5	1.4	1.4
Gas-in-Place (GIP) (Bcfe/mi^2)	65	55	130	190
Anticipated GIP Recovery Factor	40%	38%	30%	28%
Royalty	25%	17%	15%	25%
Operating Costs	\$1.25/Mcf	\$1.25/Mcf	\$1.25/Mcf	\$1.25/Mcf

Notes:

a. Data sources: All well data except royalty and operating costs are from a Chesapeake Energy investor presentation [8]. Royalty costs are from Range Resources [9]. Operating costs are from Southwestern Energy's December 31, 2009 Form 10-K [10].

Average monthly well gas production rates are estimated with the well production data presented in Table 2. The average monthly well gas production rates are then used to estimate wellhead gas prices. First, it is assumed that the expected ultimate recovery (EUR) rates listed in Table 2 are for a 30-year well production life. Second, monthly gas production estimates are generated with a standard hyperbolic shale gas well production formula.[2] The formula input values from Table 2 are the initial first month production rate (IP) and the EUR is used to extrapolate the nominal gas production decline exponent. The hyperbolic form means that gas production declines rapidly in the early years and levels off at a low decline rate in later years.

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[2] The hyperbolic formula is $Q_t = q_{ip} / (1 + bDt)^{1/b}$, where Q_t is gas production in month t; q_{ip} is the first month well production value, the IP in Table 2; t is the month of production; b is the hyperbolic decline exponent, the B-Factor in Table 2; and D is a nominal monthly well production decline rate, which is extrapolated from the well EUR.

Graphs of the average well production profiles are presented in Fig. 8. In the first year of well production, the gas production decline rate is about 55% [2, 11]. Two-thirds of a well's EUR is produced in ten years and 80% of a well's EUR is produced in fifteen years.

Shale gas wellhead prices are likely in the $6.75-7.50/Mcf range, which are weighted averages of the prices presented in Fig. 9. If average well gas production rates decrease by 40% and well costs remain constant, then the wellhead gas price increases to greater than $10/Mcf. Wellhead gas prices are estimated with the monthly well production rates presented in Fig. 8 and the well cost estimates presented in Table 2. Wellhead gas prices are estimated by the net present value, cash flow method. The underlying financial assumptions are provided in the Appendix, A-1.

It should be noted that the wellhead gas price estimates do not include state or federal subsidies, e.g., tax credits. Also, the wellhead gas prices are for dry shale gas wells. The shale gas wellhead price estimates are consistent with other estimates when the wellhead price takes into account all equity and debt capital costs as well as all operating expenses [12].

The marginal price for natural gas is assumed to be the last 15-25% of natural gas supply, which is shale gas from dry shale gas wells. Marginal price economics dictate that the market price to bring the last 15-25% units of supply to market has to be at a level that provides a market rate of return to investors. Since investor interpretations of a market rate of return vary, the shale gas wellhead price estimates are presented for rates of return on equity capital ranging from 6-10%.

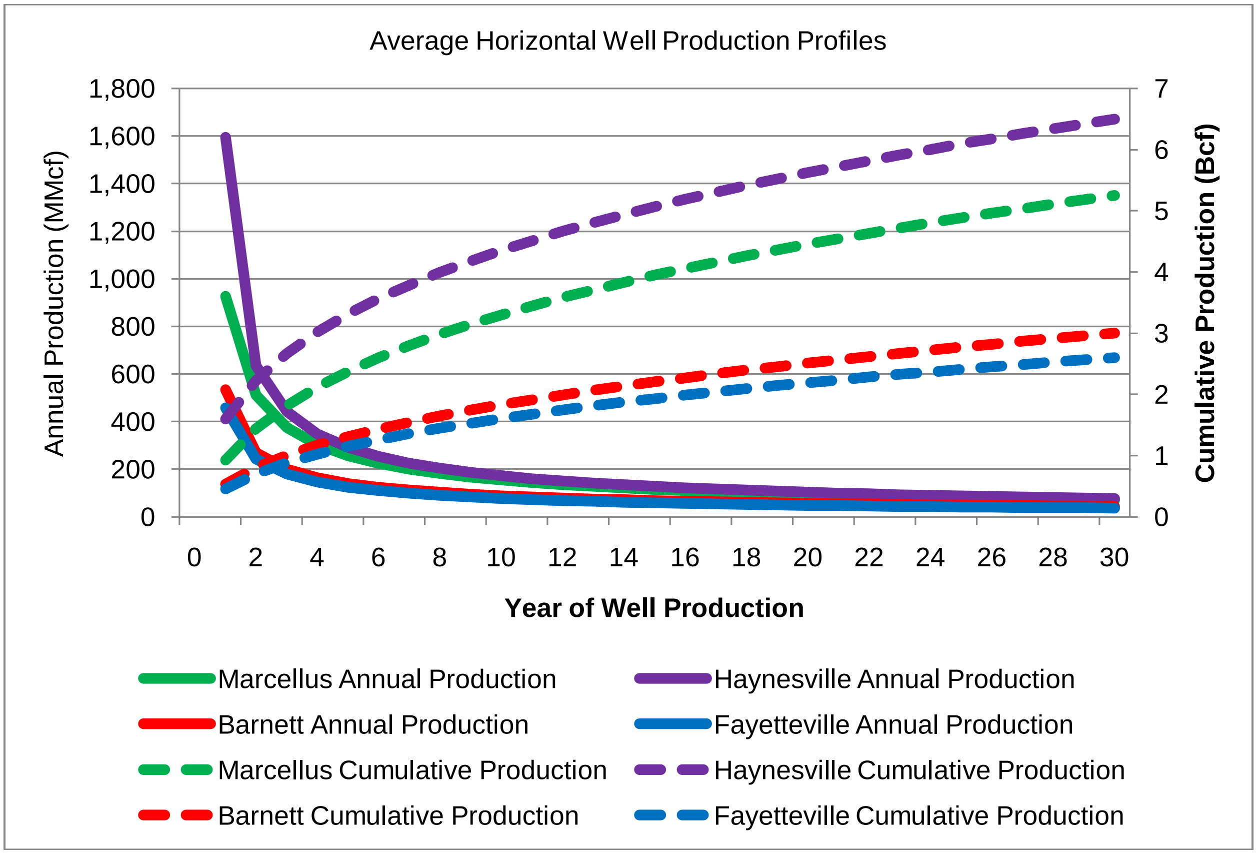

Figure 8. Average shale gas horizontal well production profiles.

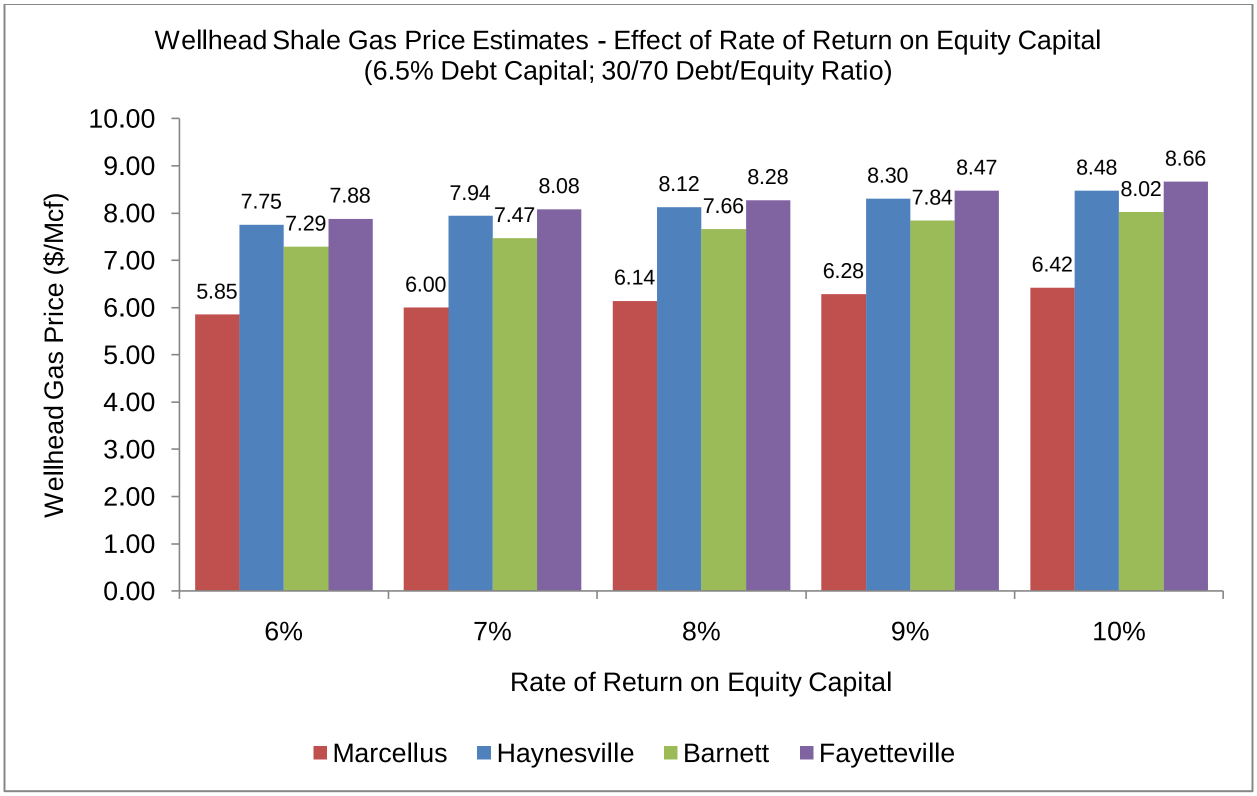

Figure 9. Wellhead gas price estimates.

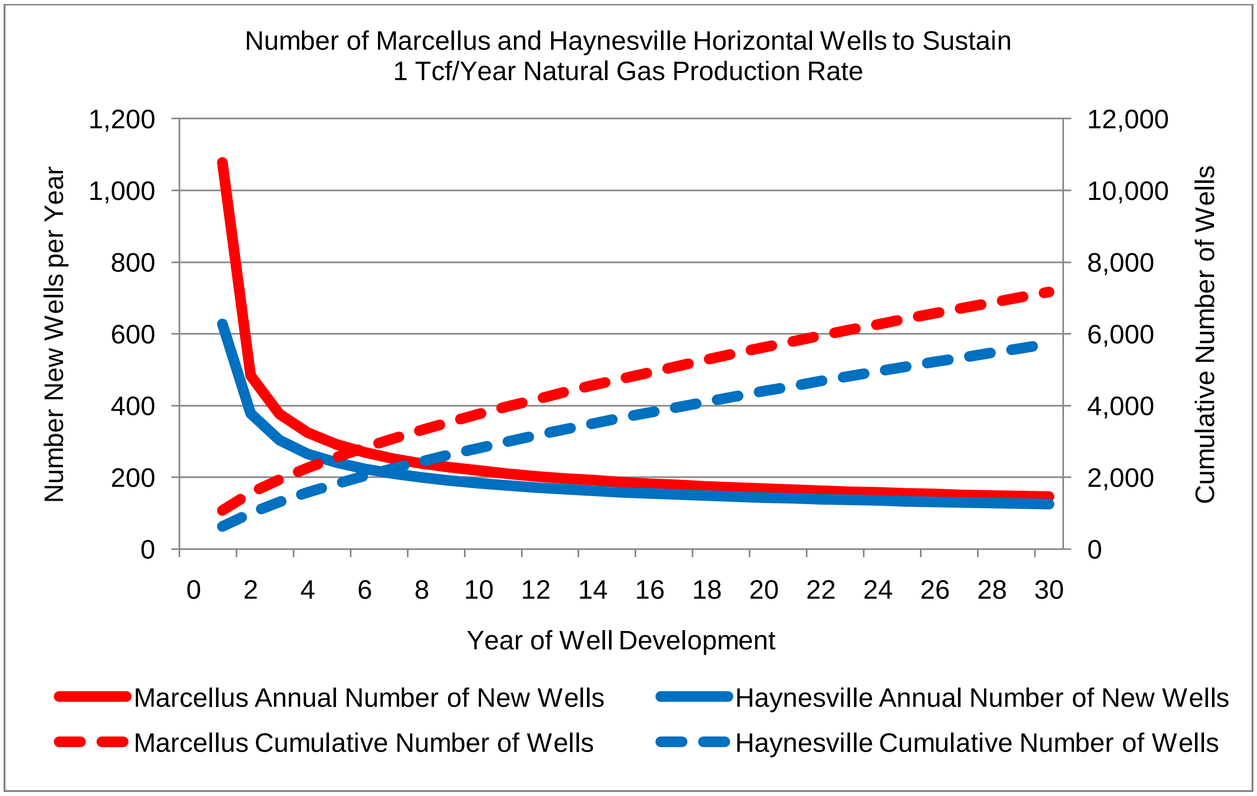

Figure 10. Number of wells to maintain an annual shale gas production rate of 1.0 Tcf.

The decline rate in shale gas production creates a need for continuous new well development to maintain a constant aggregate level of shale gas production. Of interest is the number of wells to maintain one trillion cubic feet (Tcf) increments in annual shale gas production. The number of wells to maintain a 1.0 Tcf/year shale gas production rate in the Marcellus and Haynesville plays is presented in Fig. 10 above. Shale gas production in the Marcellus and Haynesville plays is important because they contain about 75% of the U.S. shale gas resource base.

For the Marcellus play, the number of wells to initiate a 1.0 Tcf increment in annual shale gas production is 1,079 wells. The total number of wells to maintain a constant 1.0 Tcf/year shale gas production rate for thirty years is 7,165 wells. The capital cost to maintain a 1.0 Tcf/year shale gas production rate in the Marcellus play is $79 billion, which is based on the Marcellus well cost data in Table 2 and constant 2010 dollars, refer to Appendix A-1 for F&D cost entry.

For the Haynesville play, the number of wells to initiate a 1.0 Tcf increment in annual shale gas production is 627 wells. The total number of wells to maintain a constant 1.0 Tcf/year shale gas production rate for thirty years is 5,724 wells. The capital cost to maintain a 1.0 Tcf/year shale gas production rate in the Haynesville play is $104 billion, which is based on the Haynesville well cost data in Table 2 and constant 2010 dollars.

The history of horizontal well development in the Barnett, Fayetteville, and Haynesville plays indicates that the number of well completions to increase shale gas production in 1.0 Tcf/annum increments is feasible. The shale gas horizontal well production profiles are premised on core area wells. Questions remain about the timing and consequences of core area well saturation.

3. The Effect of Expanding Natural Gas Use on Shale Gas Production Dynamics

The expanded use of natural gas and the effect on long-term shale gas production dynamics are evaluated in this section. First, scenarios for the expanded use of natural gas as a transportation fuel and for added electricity generation are specified in terms of natural gas consumption and deployment rates. Second, annual and cumulative shale gas production schedules are estimated for the natural gas use scenarios. Third, factors that affect the development of shale gas plays are investigated. Of particular importance are: a) the timing of core area saturation by wells with 80 acre well spacing; and b) the timing of cumulative shale gas production reaching 50% of the shale gas TRR. Fourth, the timing of Marcellus play core area saturation by 80 acre well spacing is investigated. Marcellus shale gas supply is very important because it contains almost half of the U.S. shale gas resource base.

3-A. Scenarios to Increase the Use of Natural Gas as a Transportation Fuel and for Added Electricity Supply and the Increase in Natural Gas Consumption

The large U.S. natural gas resource base has led to proposals to expand the use of natural gas as a transportation fuel and for added electricity supply as a means to reduce oil imports and CO_2 emissions. The increases in natural gas use need to be added to the EIA business-as-usual natural gas supply forecast, which calls for 12 Tcf of shale gas in 2035. Since it has been established that shale gas is the marginal unit of natural gas supply any increase in the use of natural gas needs to be added to the EIA shale gas supply forecast.

Three scenarios are specified for the expanded use of natural gas as a transportation fuel and for added electricity supply:

1) fuel for 100% of the heavy freight truck fleet;
2) fuel for 33% of the light vehicle fleet with a 50% increase in average vehicle fuel economy;
3) fuel to replace 33% of coal electricity supply
    a. three types of power plant options
        i. natural gas combined-cycle power plants (NGCC model)
        ii. wind power with backup combined-cycle power plants (Wind-NGCC model)
        iii. wind power with backup compressed air energy storage (CAES) gas turbine power plants (Wind-CAES model).

The increases in natural gas consumption and reductions in oil imports and CO_2 emissions for the three expanded natural gas use scenarios are presented in Table 3.

Table 3. Effects of Expanded Natural Gas Use for Transportation and Electricity Generation.[a]

	Increase in Natural Gas Consumption (Tcf)	Reduction in U.S. Oil Imports	Reduction in Total U.S. CO_2 Emissions
Transportation			
NG for 33% of Light Vehicles with +50% Fuel Economy	3.5	22%	3%
NG for 100% of Freight Trucks	4.5	19%	6%
Electricity Generation to Replace 33% of Coal Electricity			
NGCC Power Plants	3.8	0%	7%
Wind-NGCC Power Plants	2.3	0%	10%
Wind-CAES Power Plants	0.6	0%	15%

Notes:
a. The fuel transition rates are 10%/year from 2015-2024, and the fuel data is from EIA [1].

The resulting range in 2035 shale gas supply is 12-24 Tcf. The low-end 12 Tcf shale gas supply estimate is the EIA business-as-usual shale gas supply forecast, which does not include the expanded use of natural gas as a transportation fuel or for added electricity supply. The high-end 24 Tcf shale gas supply estimate is for a combination of the following scenarios: 100% of heavy freight trucks; 33% of light vehicle fleet with a 50% increase in average fuel economy; and replacement of 33% of coal electricity with natural gas combined-cycle power plants.

The next step is to include Alaska natural gas supply, which reduces shale gas demand. Three Alaska gas pipelines are constructed with completion dates of 2025, 2030, and 2035. The net natural gas delivery rate of a standard 56” pipeline to the lower 48 states is 1.5 Tcf/year. The supply of Alaska natural gas from 2035 forward is 4.5 Tcf/year.

3-B. Annual and Cumulative Shale Gas Production for the Shale Gas Supply Scenarios

The annual and cumulative shale gas supply totals for the EIA business-as-usual and expanded natural gas use scenarios are presented in Fig. 11 for the shale gas only case and in Fig. 12 for the shale gas plus Alaska gas case. Alaska's annual and cumulative natural gas production totals are presented in Fig. 13. The end points of the annual and cumulative gas supply graphs are the year when cumulative production reaches 50% of the TRR estimates reported in Table 1.

What if the shale gas TRR turns out to be less than the EIA 847 Tcf TRR estimate [2, 13]? For example, the Potential Gas Committee's most likely shale gas resource estimate is 687 Tcf [13]. Also, concerns about the effects of horizontal well hydraulic fracturing on pollution of potable water supplies, waste-water disposal, and methane air emissions in New York and other states may reduce resource availability. The shale gas supply scenarios are evaluated with a reduced shale gas TRR of 635 Tcf, which is 25% less than the EIA shale gas estimate. The results for the 635 Tcf shale gas TRR are presented in Fig. 14 for the shale gas plus Alaska gas case.

The years when cumulative shale gas production reaches 50% of the 847 Tcf and 635 Tcf shale gas TRR's are presented in Table 4. The findings reveal the importance of Alaska gas supply.

Table 4. Year When Cumulative Shale Gas Production Is 50% of the Shale Gas TRR.

	Shale Gas Only (12 Tcf)	Shale Gas Only (16 Tcf)	Shale Gas Only (20 Tcf)	Shale Gas plus Alaska (7.5 Tcf)	Shale Gas plus Alaska (12 Tcf)	Shale Gas plus Alaska (16.7 Tcf)
847 Tcf TRR	2051	2043	2038	2064	2048	2040
635 Tcf TRR	2042	2036	2033	2050	2039	2034

Can shale gas supply support the expanded use of natural gas as a transportation fuel and for added electricity generation? The response is contingent on the interpretation of cumulative shale gas production reaching 50% of the shale gas TRR. When cumulative shale gas production reaches 50% of TRR, shale gas production in the core areas is saturated by wells with 80 acre well spacing and well development in the highest quality extension areas is advanced.

The implications of core area well saturation and cumulative shale gas production reaching 50% of TRR are now developed. The Marcellus play is the largest of all U.S. shale gas plays, and its production is vital to long-term natural gas supply in the U.S. The EIA estimate of the Marcellus shale gas TRR is 400 Tcf, which is 47% of the U.S. shale gas resource base [1]. The Marcellus shale gas resource is 60% greater than the Haynesville play and about ten times greater than the Barnett and Fayetteville plays, which are the third and fourth largest shale gas plays [14].

It follows that when cumulative shale gas production of the Marcellus play reaches 50% of its TRR, cumulative U.S. shale gas production will be greater than 50% of the U.S. shale gas TRR. And importantly, when the Marcellus play reaches 50% of its TRR, its core area will be saturated by wells with 80 acre well spacing. The implication of Marcellus core area well saturation is that all new U.S. shale gas production is from wells in non-core extension areas.

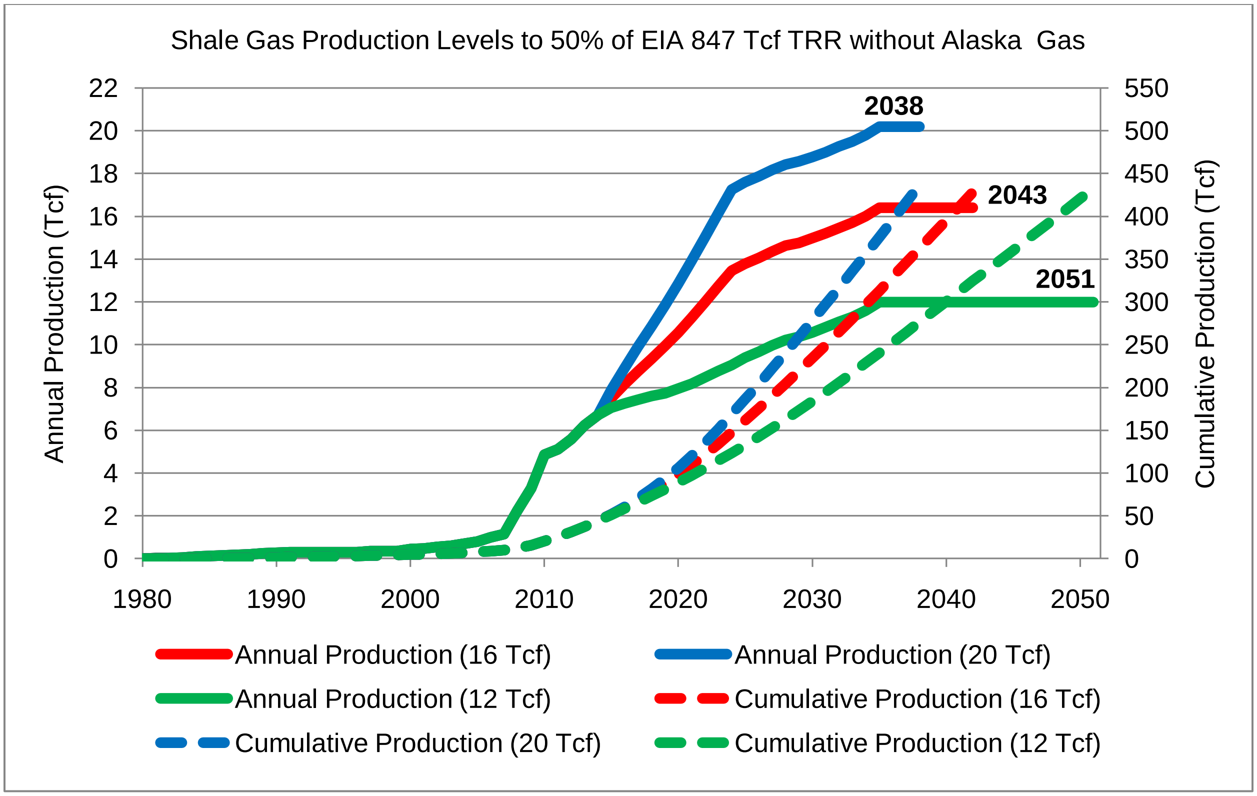

Figure 11. Shale gas production levels to 50% of the EIA 847 Tcf TRR without Alaska gas.

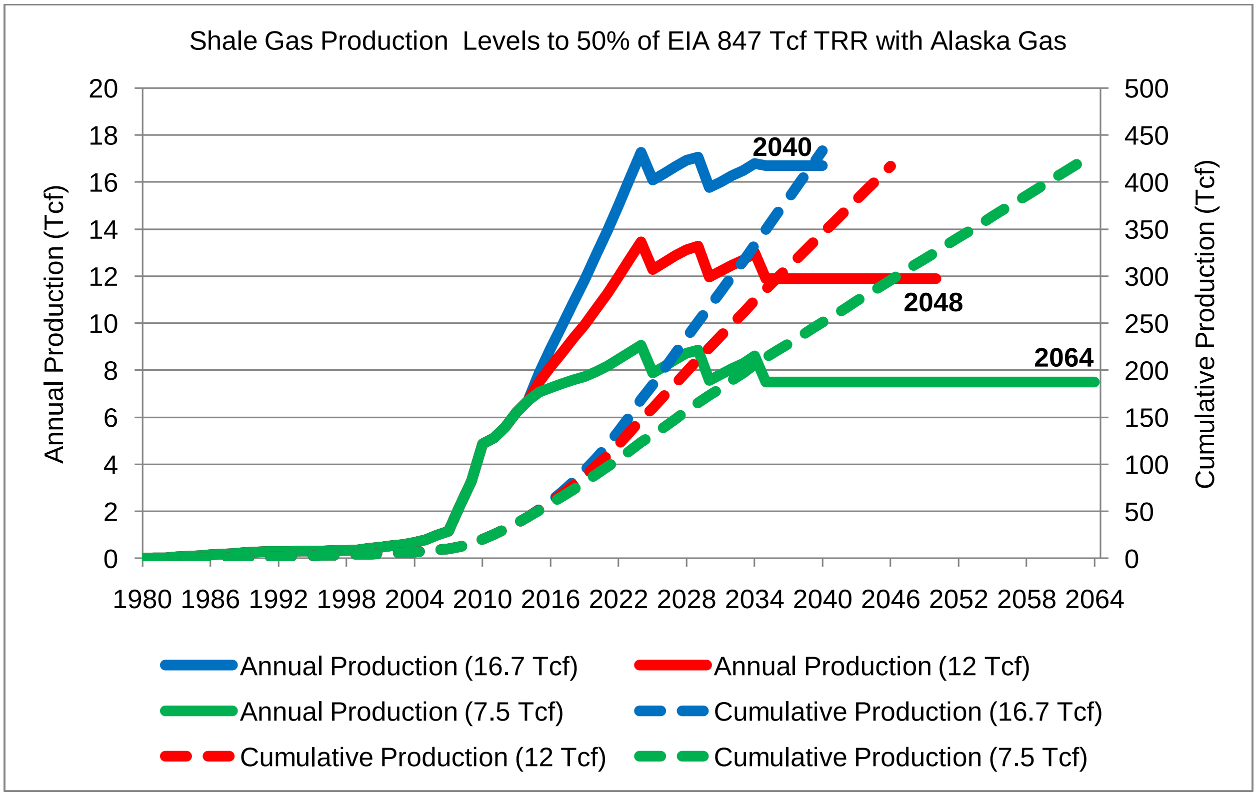

Figure 12. Shale gas production levels to 50% of the EIA 847 Tcf TRR with Alaska gas.

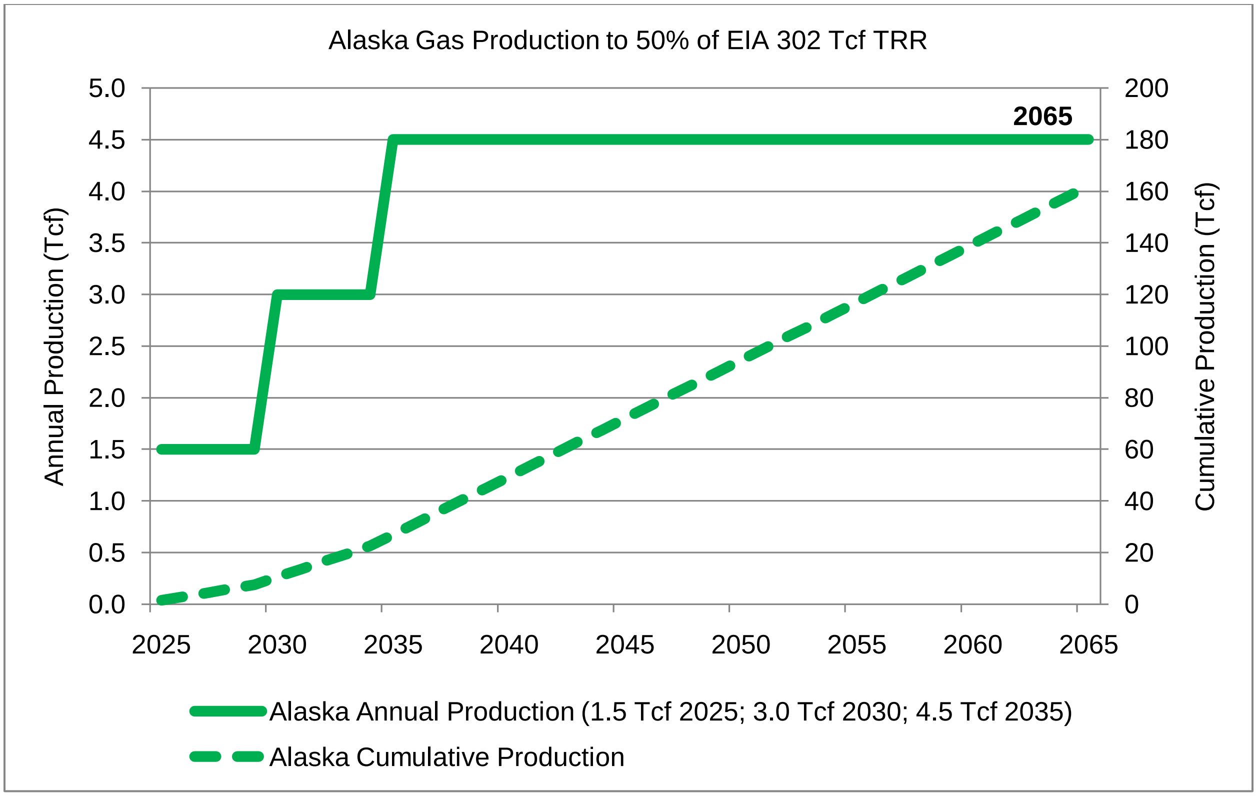

Figure 13. Alaska gas production to 50% of EIA 302 Tcf TRR.

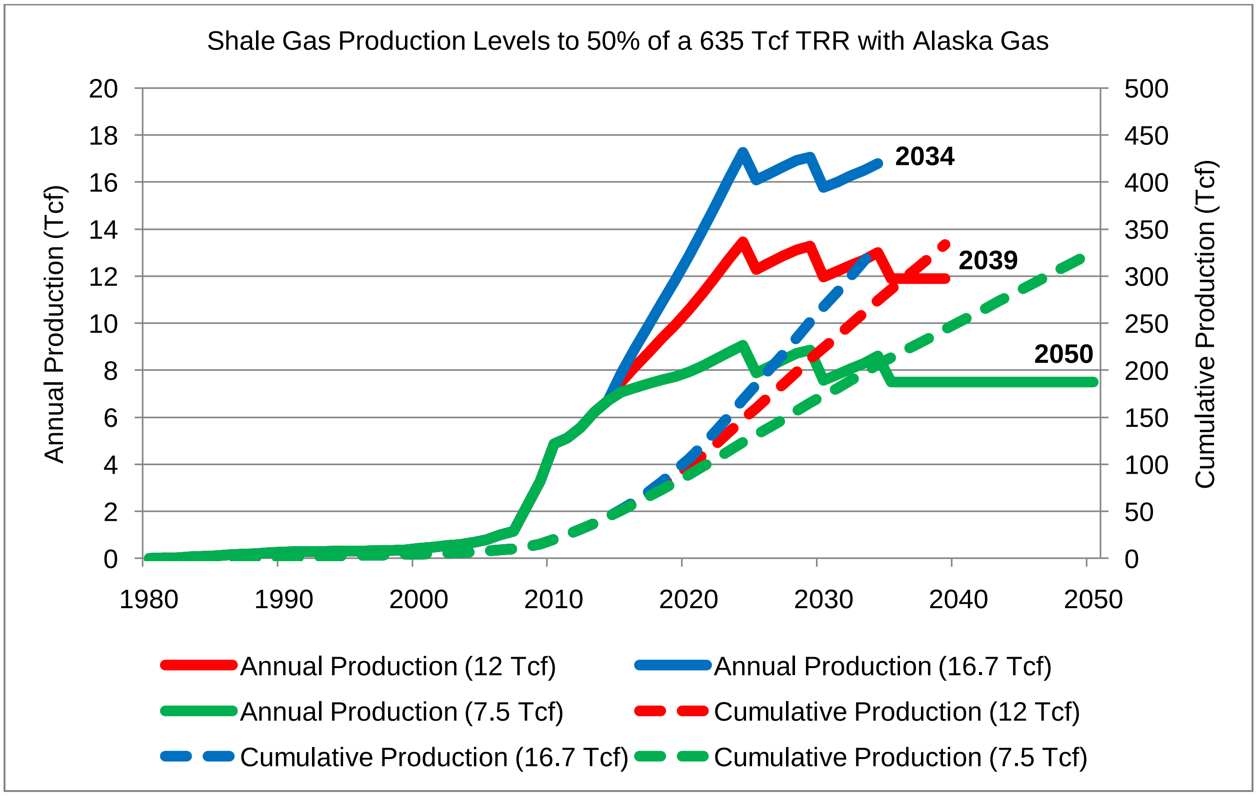

Figure 14. Shale gas production levels to 50% of a 635 Tcf TRR with Alaska gas.

The core areas of the other plays will be saturated by wells with 80 acre well spacing before the Marcellus core area. When the core areas of all major shale gas plays are saturated by wells with 80 acre well spacing, the average well production rates of extension area wells become of central importance. The average gas production rates of wells in extension areas are significantly lower than those of wells in core areas, 40+% less, as shown in Figs. 7a–7c.

Based on the well production data in Figs. 7a-7c, the average well production rate for wells with 80 acre well spacing in the highest quality extension areas is likely to be about 30% less than the average well production rate of core area wells with 80 acre well spacing. As well development in the highest quality extension areas matures, the average well production rate will likely fall to 40+% less than the average well production rate of core area wells with 80 acre well spacing. If average well completion costs are the same for extension area wells as for core area wells, then a 40+% decrease in average well production rates will increase the wellhead gas price to $10/Mcf or more.

The extension area of a shale gas play is much larger than the core area. Also, variations in shale properties are more prominent in the extension area, and the sweet spots are less prominent. Hence, it is likely that well saturation of extension area sweet spots will occur at a relatively rapid rate and result in faster declines in average well production rates. Since long-term average well production rates for extension areas are an unknown, a proxy indicator is used in this study that is based on a measure of the extent of well development in extension areas.

Well saturation of the core area occurs prior to cumulative shale gas production reaching 50% of the play's shale gas TRR. It follows that the extent of well development in the extension areas can be estimated by the length of time between well saturation of the core area and cumulative shale gas production reaching 50% of the play's shale gas TRR. The longer the time span between these two events, the more advanced is well development of the extension area. Since the Marcellus play will be the last play to saturate its core area by wells with 80 acre well spacing, it is important to evaluate the timing of well saturation in the Marcellus core area.

3-C. Shale Gas Production Dynamics

The development of a shale gas play evolves from the high quality core areas to the lower quality extension areas. When the high quality core areas are saturated, new well development is limited to the lower quality extension areas. The result is a significant decline in average horizontal well production rates and increase in wellhead gas prices. Hence, well saturation of core areas is a significant event, and the timing of its occurrence is informative.

Based on the information in Figs. 7a-7b, the average well production rate in extension areas will likely be 40+% less than the average well production rate of core area wells. An average well production rate 40+% less than the average well production rate for core area wells increases wellhead gas prices to greater than $10/Mcf. Hence, knowledge about the timing of core area well saturation is important.

3-D. Saturation of the Marcellus Core Area by Wells with 80 Acre Well Spacing

To simplify the analysis of well saturation in the Marcellus core area, the only expanded natural gas use scenario evaluated is the 12 Tcf shale gas supply scenario. This scenario calls for a 4.5 Tcf increase in natural gas demand and Alaska gas supply from 2025 forward. The Marcellus core area saturation findings will provide an important insight into the effect of a relatively moderate expansion in natural gas use on long-term natural gas supply and price dynamics.

The first step is to specify the Marcellus shale gas supply schedule. Marcellus shale gas supply is 50% of the increase in shale gas supply for the 2015-2024 fuel transition period plus 50% of the EIA business-as-usual shale gas supply. Consequently, Marcellus shale gas supply grows from 1.0 Tcf in 2012 to 5.0 Tcf in 2024. Alaska natural gas supply begins in 2025 at 1.5 Tcf and increases in 1.5 Tcf increments in 2030 and 2035, which moderates growth shale gas demand.

Post-2035 with Alaska gas supply held constant at 4.5 Tcf/year, Marcellus shale gas production is increased 0.3 Tcf/annum to meet normal growth in natural gas demand and to offset the decline in conventional onshore and offshore natural gas production. In addition, it is likely that shale gas production in the Barnett and Fayetteville plays will be in an advanced stage of development post-2035. Contingent on the economics of shale gas production, Marcellus shale gas production will likely replace shale gas production in plays with core area well saturation.

The core area of the Marcellus play is located in northeast Pennsylvania and south-central New York. Area estimates of the Marcellus core range from 6,000 to 7,500 square miles [15, 16]. One energy company defines the Marcellus core as the area of the counties in Table 5 [16].[3]

Table 5. Core Area of the Marcellus Play [16].

	Square Miles
Pennsylvania	
Susquehanna	729
Bradford	823
Tioga	1,134
Wyoming	459
Sullivan	450
Lycoming	1,235
Clinton	891
Total Area - Pennsylvania Core	5,720
New York	
Broome	707
Tioga	519
Chemung	408
Total Area - New York Core	1,634
Total Area - Marcellus Core	7,355

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[3] Area equivalencies: 1 square mile = 640 acres = one section of land.

Based on comparison of well locations in Fig. 6 with core area boundaries in Fig. 5, it is likely that only 70-80% of the Marcellus core area is viable for well development. Well development in core areas is constrained by geologic factors such as variation in shale formation properties, distribution of geologic faults and karsts, geologic rock layering conditions that control water intrusion and fluid migration, and topographical features [2]. A reasonable estimate of the net well development area of the Marcellus core area is 4,200–6,000 square miles.

It follows that the Marcellus core area is saturated by 33,600 to 48,000 wells with 80 acre well spacing and contingent on the area of the core. Based on the Marcellus shale gas production schedule stated above, the range in projected dates of Marcellus core area well saturation is 2036-2043 and is presented in Table 6. Marcellus annual gas production levels and cumulative number of wells for core area saturation are presented in Fig. 15. The average horizontal well production profile for the Marcellus core area is 5.25 Bcf EUR with 80 acre well spacing, 4,000+ foot laterals, and multi-stage fracing. Cumulative shale gas production at the time of core area saturation is 112-170 Tcf, which is 28-42% of the Marcellus 400 Tcf shale gas TRR.

Table 6. Dates for Well Saturation of the Marcellus Core Area.

	Core Area 6,000 Sq. Mi.	Core Area 7,500 Sq. Mi.
4.5 Tcf Increase in Shale Gas Supply		
70% of Core Area Availability	2036	2041
80% of Core Area Availability	2039	2043
EIA Shale Gas Supply Model		
70% of Core Area Availability	2044	2049
80% of Core Area Availability	2046	2053

To provide a context for the Marcellus core area well saturation findings, well saturation of the Marcellus core area is evaluated with the EIA business-as-usual shale gas supply schedule. Well saturation of the Marcellus core area with the EIA shale gas supply schedule occurs from 2044-2053, and the details are presented in Table 6. Marcellus annual gas production levels and cumulative number of wells for core area saturation with the EIA shale gas supply schedule are presented in Fig. 16. The EIA shale gas supply schedule extends well development in the core area by about ten years compared with the 4.5 Tcf increase in natural gas supply scenario.

In conclusion, well saturation of the Marcellus core area is likely to occur sometime around 2040 and possibly earlier if the lower estimate of the Marcellus core area should prove accurate. When Marcellus core area well saturation occurs in 2040, the cumulative Marcellus shale gas production estimate is 143 Tcf, which is 36% of the Marcellus TRR. Since the Marcellus shale gas resource is such a large portion, 47%, of total U.S. shale gas resources, it stands to reason that when well saturation of Marcellus core area occurs, well saturation in the core areas of all other shale gas plays will have already taken place.

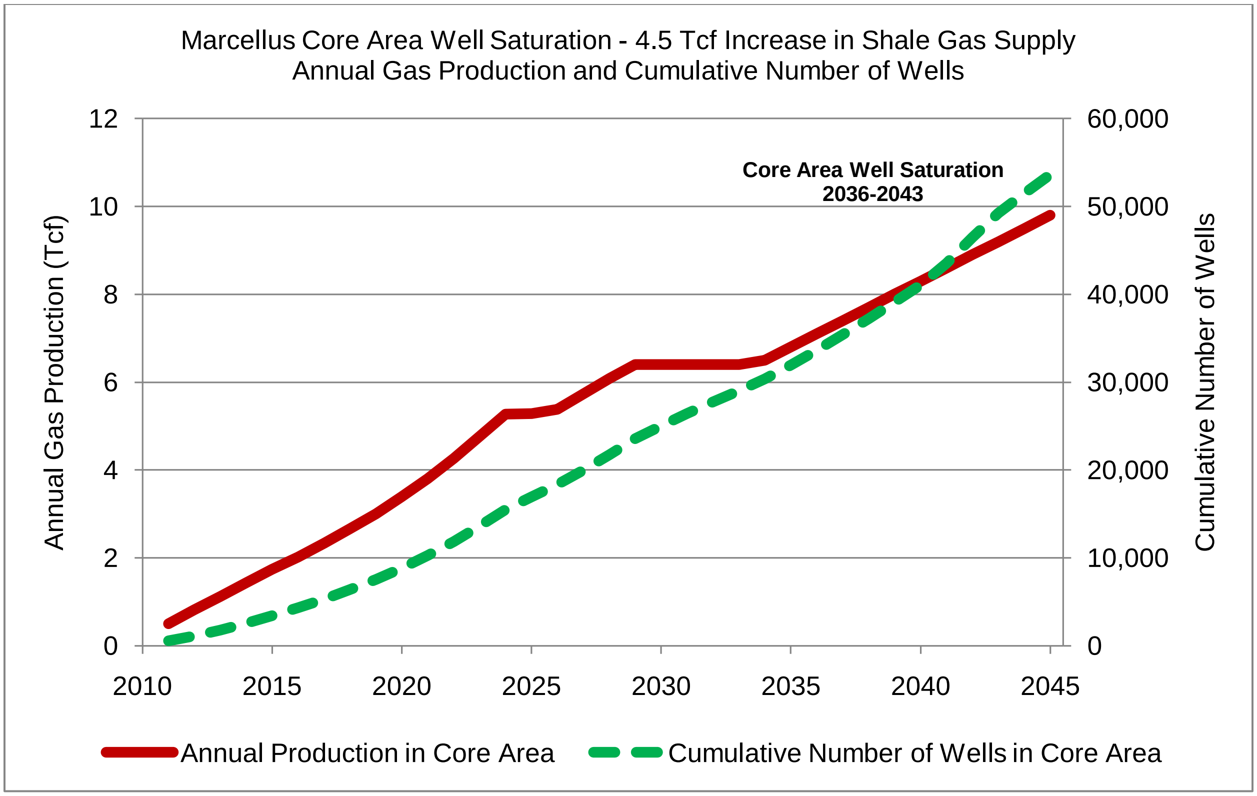

Figure 15. Well saturation of Marcellus core area with 80 acre well spacing; 4.5 Tcf Increase.

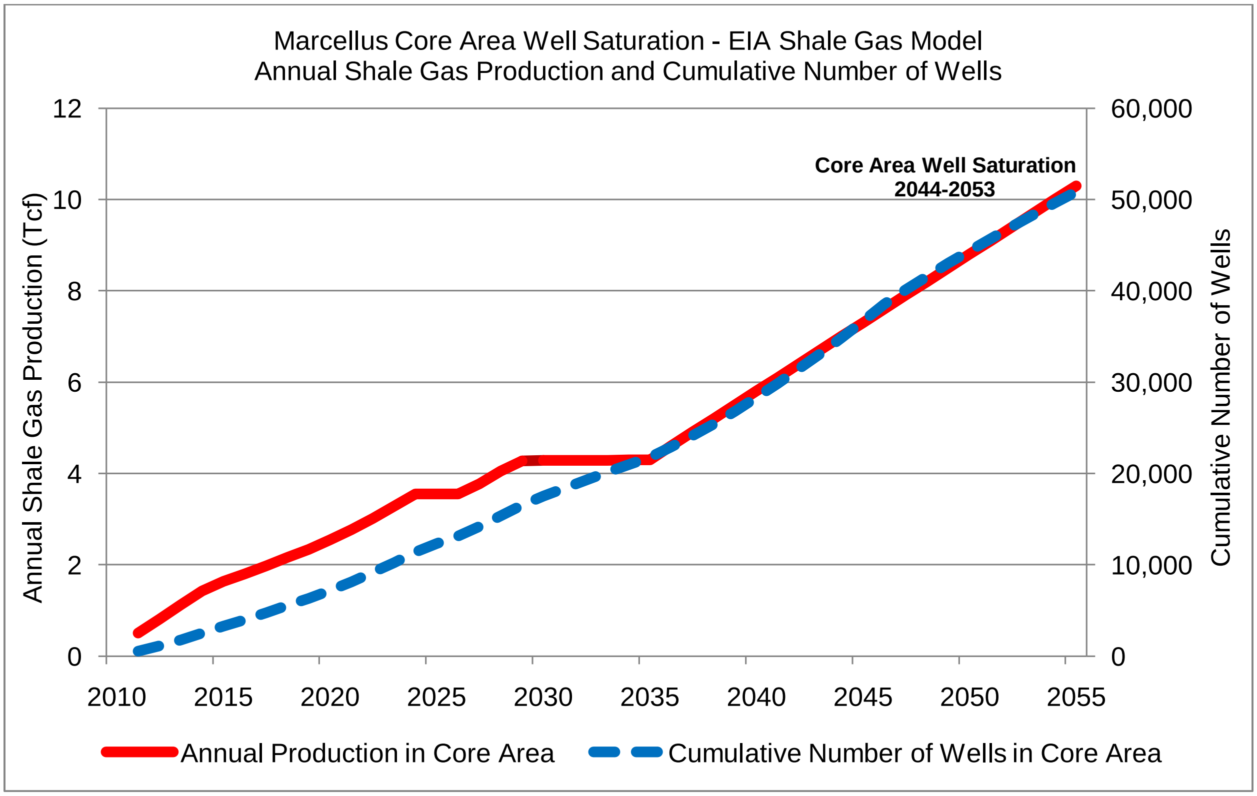

Figure 16. Well saturation of Marcellus core area with 80 acre well spacing; EIA Shale Gas.

This demonstrates the importance of the Marcellus play with a 400 Tcf TRR and the Haynesville play with a 250 Tcf TRR. When Marcellus core area saturation occurs, Marcellus average well production will be at least 30% less than the modeled Marcellus core area average well production profile that is presented in Table 2. Because of earlier dates for core area saturation in the other plays, the national average well production will likely be more than 30% less than the modeled national average well production profiles.

It follows that the national average well production rate will likely be 40+% less than the modeled national average well production rate. This expectation is based on the observation that over 50% of shale gas production will be coming from smaller plays having experienced core area well saturation prior to 2040. Furthermore, over 40% of this shale gas production will be from plays with advanced well development in the extension areas, e.g., Barnett, Fayetteville, Atrium, and Woodford plays.

If economics dictate a shift in shale gas production from plays that experience core area well saturation to plays that have not experienced core area well saturation, then the burden of shale gas supply increases for the larger plays. The increase in shale gas production in the larger plays causes greater well development rates, which translate into earlier dates of core area well saturation. Again, the national average well production rate will likely be 40+% less than the core area average well production rate, and wellhead gas prices will be greater than $10/Mcf.

With a 4.5 Tcf increase in natural gas use as a transportation fuel and with the addition of Alaska natural gas supply, the Marcellus core area saturation findings suggest that all new U.S. shale gas production post-2040 will likely be from extension area wells. In addition, the Marcellus cumulative shale gas production estimate at the time of core area well saturation supports the assumption that core area well saturation of all U.S. shale gas plays will occur prior to cumulative U.S. shale gas production reaching 50% of the U.S. shale gas TRR.

Cumulative shale gas production reaches 50% of the U.S. shale gas TRR in 2048 for the 12 Tcf shale gas supply scenario with a 4.5 Tcf increase in natural gas supply for transportation. This finding is presented in Table 4 and Fig. 12. The national average well production rate will be even less in 2048 when cumulative shale gas production reaches 50% of the U.S. shale gas TRR. In 2048, well development in extension areas will be in an advanced stage of development because of the high annual shale gas production levels. This means that average well production rates will be declining and wellhead gas prices increasing.

On a final note, peak resource production theory predicts that annual shale gas production levels will begin to decline when cumulative shale gas production reaches 50% of the shale gas TRR [17, 18]. This prediction is based on the notion that all core area and extension area sweet spots have been exploited when cumulative production reaches 50% of the shale gas TRR. The ability to find profitable locations for new well development becomes ever more difficult, costly, and riskier. The combination of geologic and economic constraints will cause decline in annual shale gas production levels. When U.S. shale gas production goes into decline, U.S. natural gas production goes into decline. By this time it is unlikely that foreign gas imports will be an option due to the rate of growth in natural gas demand in developing economies such as India, China, Brazil, etc. Also, the supply of natural gas hydrates is speculative and will be costly.

4. Conclusions

The findings of this study raise questions about the efficacy of expanding natural gas use as a transportation fuel or for added electricity generation. This conclusion holds even with the addition of Alaska natural gas supply. It needs to be emphasized that the findings in this study are based on high-end well production rates and a high-end EIA shale gas resource estimate. If the shale gas resource is less than the EIA 847 Tcf TRR estimate or if average well production rates are lower than the rates listed in Table 2, then natural gas supply constraints and corresponding steep price increases could occur before 2040.

Long-term natural gas supply stability and relatively low prices are important to the U.S. economy because two-thirds of natural gas demand is for residential, commercial, and industrial space and water heating. A large increase in natural gas prices for space and water heating will have a negative effect on the U.S. economy. With oil becoming unaffordable, electricity is the only viable option to natural gas as an energy source for space and water heating. If electricity is used for space and water heating, then the cost is at least three times greater than natural gas. Therefore, a judicious recommendation is to conserve natural gas resources and maintain stable natural gas supply for as long as possible.

If shale gas supply is limited to about 8 Tcf/year, which represents the business-as-usual scenario with 4.5 Tcf Alaska gas supply and no expansion of natural gas use, then stable natural gas supply can be expected through 2050 at relatively low prices, $8-9/Mcf. On the other hand, the findings of this study indicate that if shale gas supply is used to expand the use of natural gas as a transportation fuel or for added electricity generation, then shale gas production is relegated to extension area wells by 2040. The implication is a wellhead gas price greater than $10/Mcf.

It needs to be taken into consideration that there are several factors that could limit the use of shale gas supply. One possible limit to future use of shale gas supply is greater than expected declines in conventional onshore and offshore natural gas production, which would have to be offset with shale gas supply. Another factor that could limit the use of shale gas supply is growing concerns about hydraulic fracturing methods used to extract commercial quantities of shale gas. Recent peer-reviewed research findings report pollution of potable water supplies and the release of greenhouse gases related to shale gas recovery [19, 20].

Citizen groups in the Marcellus core area are calling for a ban on hydraulic fracturing and stricter regulations. The public concerns about water pollution, waste-water disposal, and other negative environmental effects of shale gas production by hydraulic fracturing are growing nationwide. The public concerns will likely result in stricter regulations and may even result in a reduction in the areas available for shale gas production, both of which will increase wellhead gas prices.

Still another factor that could possibly limit the use of shale gas supply is the export of U.S. natural gas to foreign countries. The surplus in natural gas supply created by the dramatic increase in shale gas production has led to proposals to convert the natural gas import facilities built in response to the 2002-2008 natural gas supply shortage into natural gas export facilities [21]. Also, there is a proposal for an Alaska natural gas pipeline from the North Slope to a Valdez, Alaska liquid natural gas terminal for export to Asia [22]. If U.S. onshore shale gas and

Alaska North Slope natural gas are exported to other countries, then the portion of the U.S. natural gas resource base available to meet long-term U.S. domestic needs is reduced.

Two of the rationales for expanding the use of natural gas as a transportation fuel and for added electricity generation are to reduce oil imports and CO_2 emissions. However, the reductions in oil imports and CO_2 emissions accruing from the expanded natural gas use scenarios listed in Table 3 are not impressive. Solar and wind electricity technologies offer an alternative path.

The U.S. has a large solar energy resource base in the Southwest states and a large wind energy resource base in the Midwest states. The U.S. solar and wind energy resource base is capable of sustaining solar and wind electricity production, as well as electrolytic hydrogen production with solar and wind electricity to supply 100% of the nation's transportation and electric sector energy needs through 2100 and beyond [23, 24].

A concern about solar and wind electricity is variable electricity supply caused by changes in sunlight levels and wind speeds. Fast responding natural gas turbine power plants are used to firm variable solar and wind electricity supply. This raises the issue of natural gas consumption by the power plants used to firm variable solar and wind electricity supply.

To provide insight into the quantity of natural gas consumed by power plants supporting the large-scale supply of solar and wind electricity, two types of fast responding gas turbine power plants are evaluated. The first type of power plant is a conventional natural gas combined-cycle (NGCC) power plant. The second type of power plant is an advanced compressed air energy storage (CAES) gas turbine power plant. The natural gas consumption rates for Solar-NGCC, Solar-CAES, Wind-NGCC, and Wind-CAES power supply reported below are based on prior research [25, 26].

The EIA estimates that the electric power sector consumes 7.0 Tcf of natural gas in 2011 [1]. If wind and solar electricity supplies 100% of the electricity currently supplied by natural gas, coal, nuclear, and oil power plants, which is 3,343 trillion watt-hours of electricity, then 12.7 Tcf is consumed by the NGCC power plants that are used to firm the solar and wind electricity supply. This is a 5.7 Tcf increase in the quantity of natural gas consumed by the electric power sector.

In contrast, if CAES gas turbine power plants are used to firm solar and wind electricity supply, then only 3.8 Tcf of natural gas is consumed by the supporting CAES plants. This is a 3.2 Tcf **reduction** in natural gas consumption by the electric power sector. With CAES power plants supporting solar and wind electricity supply, solar and wind electricity can supply 100% of U.S. electricity with a 46% reduction in natural gas consumption for electricity generation. This enhances the long-term supply of U.S. natural gas resources. Also, the complete replacement of coal, petroleum, and natural gas electricity with solar and wind electricity reduces total U.S. CO_2 emissions by 36%. If solar and wind electricity is used for electrolytic hydrogen production for a transportation fuel, then U.S. CO_2 emissions can be reduced by more than 50%.

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Appendix

A-1. Financial Assumptions for Shale Gas Wellhead Price Estimates.[a]

Well Production Life	30 Years
Debt/Equity Ratio	30/70
Return on Equity Capital	6-10%
Return on Debt Capital	6.5%
Debt Payback Period	10 Years
Real Discount Rate	Weighted Average Cost of Capital, 2.39-5.19%
Royalty Rate[b]	Variable
Depreciation	10 Year MACRS
Working Capital	10% of O&M
Well Maintenance and Replacement Costs	5% of Capital in Year 15
Well Refrac Cost	25% of Capital in Year 16
Income Tax Rate[c]	39%
Severance Tax[d]	Variable
Average Annual Inflation Rate	3%

Notes:

a. Well cost and gas production data are presented in Table 2. It should be noted that the finding and development (F&D) costs in Table 2 are presented terms of $/Mcf of gas recovery over the well's production life but are entered as capital costs by multiplying the cost by the well's EUR. The "all in" capital costs are all finding and development costs, which include such costs as land procurement and development costs, water system costs, waste water disposal system costs, and gas gathering systems costs, as well as well drilling and completion costs [27].

b. The royalty rates presented in Table 2 are 25% for the Barnett and Haynesville plays, 17% for the Fayetteville play, and 15% for the Marcellus play.

c. It is assumed that there are no production tax credits for shale gas production.

d. States' impose severance taxes and they vary. The Texas severance tax rate is 7.5% for the Barnett play, the Louisiana severance tax is $0.164/Mcf for the Haynesville play, the Arkansas severance tax is 5% (with a reduced rate for the first three years) for the Fayetteville play, and the West Virginia severance tax is $0.047/Mcf plus 5% of the value of the gas produced for the Marcellus. Pennsylvania and New York do not have a severance tax at this time, but the Pennsylvania legislature is considering the imposition of a severance tax similar to West Virginia's. For purposes of this study, a severance tax of $0.47/Mcf plus 5% of the gas produced is assumed for all states in the Marcellus play.